Commission to consider in determining the level of price risk to which Edison is exposed in meeting its ongoing supply responsibilities. (*See* Edison Exhibit 9.0 at 4; Edison Exhibit 8.0 at 5.) Edison is asking the Commission to increase rates for delivery services customers to account for a cost of capital risk premium that the market is supposedly extracting with respect to supply price risk following the mandatory transition period.

Edison's proposition to the Commission is simple enough, it can be paraphrased as follows:

> "We divested all of our generation, flowed a substantial gain to our bottom line, increased our post-transition risk and want delivery services customers to pay us for that increased risk even though we may not even supply them with power and energy."

While it may often be tempting to ridicule Edison's repeated unabashed requests to have it both ways, this particular fact pattern brings to mind the old analogy of the young man who murdered his parents and then sought mercy from the court because he was an orphan.

Edison is seeking to include in the cost of delivery services a cost that has nothing to do with the provision of delivery services. This violates the law.

Q. **What steps should the Commission take to ensure that it approves an appropriate capital structure?**

A. **First** and foremost, the Commission should resolve that any risk premium associated with supply price risk should not be reflected in the rates charged for delivery services. This concept is a maxim of a truly deregulated environment.

Second, the Commission should reject the capital structure currently reflected in Edison's filing and impute an appropriate capital structure to the delivery business that reflects an efficient that matches the nature of the delivery business alone. Edison's company-wide capital structure is a vestige of its vertically integrated past and may well not be a proper structure solely for the purpose of delivery services. Edison has a single shareholder, Exelon. The corporate leadership of Exelon determines the capital structure of Edison to suit its view of financial efficiency for the entire Edison enterprise – not merely for the delivery segment of the business. The Commission should impute an appropriately leveraged capital structure for what must be considered a relatively low risk business in which the revenues from the business would be relatively steady and predictable.

Third, the Commission should impute a cost of equity that would be appropriate exclusively for the delivery business, taking into consideration the imputed capital structure suggested above.

Fourth, the Commission should consider an allocation of differing and appropriate debt costs between the supply business and the delivery business. While much of the invested capital in Edison relates to delivery services, to the extent that debt costs are higher due to supply obligations, those additional debt costs should be allocated for recovery through supply charges.

Finally, the Commission should make matters simpler and reduce the problems for the competitive market by adopting the suggestion presented above and act promptly to sever the non-residential rate changes from the instant proceeding. This would allow the competitive market to move forward with the established non-residential rates while the Commission proceeds to set residential rates as best it can.

<u>Relationship To PPO-MVI Tariffs</u>

Q. Please discuss the sixth policy consideration that relates to the role of the MVI tariff in addressing Edison's supply risks.

A. The Customer Choice Act is extremely generous to Edison in providing mechanisms for Edison to limit its supply risk. The most important of these mechanisms, especially insofar as the post-transition period is concerned, is the PPO-MVI tariff. Edison has been free to use a methodology of its own design for the estimation of the market value of power and energy. While most of the attention given the PPO-MVI tariff has focused on its role in the setting of CTCs and the price of power and energy under the PPO, the MVI also is the basis for the recovery of the substantial supply cost component of bundled service by Edison in the post-transition period. The Customer Choice Act allows Edison to collect after the transition period as much as a 10% premium, if justified, over the established MVI. (*See* 220 ILCS 5/16-111(i).)

It is noteworthy that during the most recent proceeding to approve the Edison PPO-MVI tariff, Edison argued strenuously, and the Commission seemed to agree, that Edison's MVI tariff fully provided for the value or cost of "optionality" related to the potential of serving unanticipated load. While AES NewEnergy argued that the Edison PPO-MVI tariff was deficient in this regard, Edison prevailed in its argument that the PPO-MVI tariff adequately addressed the risks of "optionality."

It is Edison's MVI tariff upon which the price of supply will be based for any supply obligations Edison may have post-transition. Edison previously has asserted that its MVI tariff properly reflects the market value of power and energy. This point is not addressed by Edison's witnesses in the instant proceeding.

Q. Is Interim Supply Service (ISS) another mechanism available to Edison for mitigating supply risk in its role as provider of last resort?

A. Originally, in the 1999 delivery service case, this Edison tariff was called Transition Service (Rate TS-Default Service). As its name implies, it was designed to charge a delivery services customer, whose RES or ARES failed to deliver supply, a market based price for supplying power for a maximum of three months if an ARES defaulted on its contract to supply a retail customer. During the maximum three months that a customer could remain on Transition Service, the customer could seek out another ARES, go to the PPO or return to bundled service. The market price was set monthly and based on the NYMEX Cinergy Index and on Platts. In this way, Edison would be protected from any appreciable supply price risk.

For reasons never fully explained since the Commission acted on a pass-to-file basis, Edison later chose to change the name to Interim Supply Service ("ISS") and change the pricing period to the Period A and B time frame used for the PPO-MVI. Under the new ISS tariff, prices happened to fall below those of the PPO-MVI for the comparable PPO-MVI time periods. According to Edison's response to ARES Coalition Data Request 1.19, the result was that an unexpectedly large number of delivery services customers were switched to ISS. Edison has so far declined to indicate which RES or ARES were more heavily involved in the switching of customers to the ISS tariff and which RES or

ARES then switched customers back to flowed power or to PPO assignment. Such behavior would suggest the use of the ISS as a source of supply – one that was priced by Edison's actions below PPO prices. It would be precisely this sort of "gaming" that Edison witness Juracek inveighs against. (*See* Edison Exhibit 1.0 at 14).

Recognizing the problem, Edison again petitioned the Commission for a speedy change in ISS tariff pricing to make it equal to PPO pricing. Now, in a fourth version of Default Service, the Company is asking that the Commission approve new pricing that would include a penalty or premium of 10% over the PPO price in order to discourage gaming.

It should be noted that Edison was primarily responsible for inducing what gaming has taken place with respect to Default Service by fiddling with the tariff and moving away from a key principle it has espoused – Edison voluntarily abandoned its claimed need to avoid a service of less than a year at price equal to or less than the year long PPO service price. Delivery services customers should not be expected to compensate Edison for supply price risks that Edison itself seems to incur by reason of its own actions.

In addition to ISS, there is every reason to believe that in the future Edison will seek approval to mitigate its risk by continuing, subsequent to the mandatory transition period, the requirement that any non-residential delivery services customer returning to bundled service must do so for at least twelve billing cycles.

Q. Are there supply price risk factors cited by Edison witnesses that are the result of Edison's own voluntary actions?

A. To the extent that there are factors that may serve to increase risks associated with Edison's supply obligations, it is Edison itself who has most exacerbated the situation. Edison has proposed delivery services tariffs that would have the effect of making the future of other suppliers serving customers more uncertain and inducing uncertainties among customers when considering delivery services. Discontinuities in delivery services rates increase the riskiness of the climate for delivery services.

The essential point is that the Customer Choice Act provides significant opportunities for Edison to mitigate its supply risk and that the extent to which these mechanism are implemented is largely in the hands of Edison. To the extent that Edison (or its shareholder Exelon) chooses not to use them or uses them in an imprudent or unreasonable manner, neither the Commission nor customers are required to make up any resulting loss to the Company.

Q. What should the Commission do to assure the proper use of the PPO-MVI tariff in mitigating Edison's post-transition supply price risk?

A. The most important thing the Commission could do in this area is to direct Edison to undertake efforts to revise the MVI calculation method to properly reflect any supply price risks. The revisions would specifically include the optionality costs associated with any obligation to serve uncertain load, something that Edison has previously claimed it has already done. The Commission should ensure that only the costs of capitol associated with delivery services are recovered in delivery service rates; the costs of capitol associated with generation services should be reflected in the MVI calculation.

Continuity Of Rates/Rate Shock

Q. Please discuss the seventh policy consideration relating to the value traditionally placed by the Commission on continuity of rates.

A. One of Bonbright's principles of ratemaking is the desirability of maintaining some reasonable degree of continuity of rates over time.

> "Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity."

(*Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R. Kamberschen, Public Utilities Reports, Second Edition, p 383.)

The Commission has been no stranger to this principle over the years. While this is not to say that rates should not be modified to reflect changing costs and circumstances, efforts should be made to moderate changes so that any changes that are implemented are done so after a thorough Commission review to limit the degree that such changes may be considered to be radical and dramatic. The Edison DST filing, which seeks a $575 million revenue requirements increase after less than two years of open access, is clearly radical and dramatic. The 47.5% or 37% increase Edison requests is further exacerbated for some customers by certain rate design changes and represents significant discontinuities in rates.

As discussed above, AES NewEnergy has analyzed the effect of the Edison filing on the 872 accounts served with flowed power by AES NewEnergy and that we believe can be reasonably extrapolated to help us understand the effects on the full population of current delivery services customers. The analysis shows that Edison's proposal significantly upsets the existing savings structure and in doing so would negate much of the effort made by ARES the past two years in marketing, creation of pricing models, customer development and supply acquisition. This is precisely the sort of disruption the Commission should be vigilant about preventing. It should be noted that while Edison acknowledges that rate shock should be considered, the Company apparently has made no effort to assess the customer impact of its rate increase plan (*See* Edison Response to ARES Coalition Data Requests 1.18, 4.17-18.)

Q. What should the Commission do to ensure rate continuity and prevent rate shock?

A. Given Edison's inflated revenue requirements proposal, hyperbolic figures which were created through the use of atypical test year expenditures, the re-allocation of costs traditionally recorded as production-related and the inclusion of capital costs of supply unrelated to delivery services, the Commission should find substantial room in which to achieve rate continuity. In doing so, the Commission can avoid the predictable result of the Edison request which is the forced return of delivery services customers to bundled service that would be a clear reversal of the progress made by the Commission toward a competitive environment.

Q. Are there other problems with Edison's proposed rate increase about which the Commission should be aware?

A. Yes. These include:

- The problem for rate continuity posed by Edison's proposed Rider, High Voltage Delivery Service ("HVDS") and its proposal to abandon the monthly demand ratchet and replace it with an annual ratchet;

- the use of the marginal cost of service rather than the current embedded cost of service;
- the virtual elimination of credits for unbundled services such as metering;
- the anti-competitive impact of Edison's proposed retooling of the MSP credit; and
- the virtual elimination of the Single Bill Option (SBO) credit.

Q. Please explain the problem for rate continuity posed by Rider HVDS and annual ratchet proposals.

A. At this juncture, not even midway through the mandatory transition period, Edison's proposals upset the apple cart and introduce additional uncertainty into the developing competitive market. These two proposed changes should either have been made at the outset in the 1999 delivery services case or should await the general rate case that will likely be filed in 2004. In the alternative, things might be different if Edison had come forward with these two proposals in the context of a revenue neutral case rather than in the context of a pumped up revenue requirements increase of $575 million as Edison has.

Rider HVDS proposal is a half-hearted effort by Edison to respond to criticism in the 1999 case that the Company had ignored its obligation under the Choice Act to reflect voltage level in rates. At the time, Edison claimed that its proposed customer demand rate classes were "highly correlated" with voltage levels. However Edison either refused or could not tell the Commission the strength or significance of that correlation. Nor does Edison tell the Commission even now what that asserted correlation is. The problem is that Edison has assumed without proving that the HVDS effect should be to increase the rates of most delivery services customers in classes 8 and higher. If such an increase were approved, this would strike at the heart of the current savings structure under which competition has begun to develop.

While Edison has presented some information that recognizes the obvious fact that customers taking power at high voltage are less costly to serve, Edison has presented little in the way of a demonstration that other non-residential customers served at less than 69 kv should see their rates increased. The General Assembly contemplated that the Commission would find that very large customers might have a lower cost of service and that voltage should be reflected in rates. (*See* 220 ILCS 5/16-108(d).) It also contemplated that Edison could take steps to reduce rates in a speedy and easy fashion if it chose to do so. (*See* 220 ILCS 5/16-111(f).)

> "During the mandatory transition period, an electric utility may file revised tariffs reducing the price of any tariffed service offered by the electric utility for all customers taking that tariffed service, which shall be effective after 7 days notice."

This is in stark contrast to Section 16-111(a) of the Customer Choice Act that prohibits rate increase filings by utilities prior to the end of the mandatory transition period by a utility other than for some exceptions which do not include delivery services rate filings other than those required in order to establish initial delivery service rates prior to the commencement of open access. While the Commission is free to modify such initial tariffs, the utility cannot file for an increase in the rates in those tariffs.

The solution to the acknowledged overcharging of customers taking service at 69 kv is for Edison to exercise its prerogative under Section 16-111(*f*) of the Customer Choice Act to reduce their rates on 7 days notice. (*See* 220 ILCS 5/16-111(f).)

Q. Please explain your position with respect to Edison's proposal to rely on Edison's marginal cost of service study for the allocation of costs in this case.

A. Again, it would be one thing if the Commission had accepted Edison's marginal cost of service proposal in the 1999 delivery services tariffs case.. However, the Commission chose to rely on an embedded cost approach. At this point, regardless of whether there may be merit in a marginal cost approach, the switch in the middle of the mandatory transition period would disrupt the savings structure that the open access market has operated under the past two years. The adoption of a marginal cost approach should at least await the end of the mandatory transition period. Clearly, Edison anticipates that this will be the case. The Company has provided an embedded cost of service study for the Commission to use. Unfortunately, Edison appears to have another motive for advancing the marginal cost approach. Doing so would gut the Commission's recent Orders providing for the unbundling of services, switching to a marginal cost based credit would reduce customer credits for unbundled services to nearly zero.

Q. How would Edison's proposed use of a marginal cost methodology impact competitors' ability to provide unbundled delivery services?

A. Of course, Edison has been opposed to the Commission's decisions over the past year or so allowing competitive entry into metering. Now, in an attempt to get another bite at the apple, Edison again proposes using marginal cost of service methodology to establish the credit customers receive when they choose alternative suppliers. Accepting Edison's position would place the Commission in the position of telling customers and new competitive entrants that even though they opt for another source for an important and perhaps expensive service, they would still have to pay Edison just about as much as they did when Edison provided the service. While Edison purports to offer its avoided cost approach as a way of "getting prices right," the simple truth is that Edison is seeking to extend the stranded cost regime to the point of a "tails I win, heads you lose" situation for the customers and new entrants that are seeking new and better ways of measuring energy use.

Q. **Aside from the methodology used to determine the credit, please describe Edison's proposal to change the size of the credit available to meter services providers ("MSPs").**

A. Edison's proposed revisions to its standard metering charges and the associated MSP credit amount to a "bait and switch" that would have a devastating anti-competitive impact upon the development of competition in metering services.

Q. **Has the Commission already addressed the issue of cost credits for customers choosing an alternative meter service provider.**

A. Yes. In the unbundling proceeding, ICC Docket No. 99-0013, the Commission completed its almost two (2) year investigation into the provision of unbundled metering service by setting the credit for metering services. It appears that Edison is yet again trying to change the rules of the game at the expense of customers who elect to use a competing MSP.

Q. Please explain.

A. On October 4, 2000, the Commission entered a Final Order re-affirming the methodology that should be used to calculate the MSP credit. In short, the credit is equal to the "standard metering service charge" for any customer. Edison filed tariffs in accordance with the Commission's Final Order. Now, Edison has proposed gutting the current credits. As a result, a MSP that has invested in supplying competitive metering services and been certified by the Commission, and potentially having been approved by Edison after testing, now would find itself facing a **reduction** in the credit by as much as **17,500 percent**. A reduction of this magnitude by Edison, could force the lone certified MSP and any other potential MSPs out of the Illinois market. This is no doubt the game plan.

Q. Please explain how Edison is proposing to reduce the MSP credit in the instant proceeding.

A. For customer meters in the 6,000 - 10,000 kW customer class, Edison proposes the most drastic change; a reduction from $172.56 to $0.98 or 17,550 percent. For customer meters in the 800 – 1,000 kW customer class, Edison proposed reduction is 2,900 percent, from $29.14 to $0.98.

Q. How will Edison's proposed revisions to its MSP credit impact RES like AES NewEnergy?

A. An MSP offering competitive metering service provides a number of value-added services that allows RESs to incorporate a metering system from an MSP that works best for the RES and its customers. However, the Edison filing seeks to ensure that Edison continues in its position as the monopoly metering service provider by not providing the appropriate cost credits to customers that choose an alternative to Edison.

Q. Do you believe that Edison's proposed standard metering service charges are appropriate for customers who have switched to a competitive MSP?

A. Based upon a review of Edison's testimony, exhibits, and "responses" to data requests, it appears that Edison has failed to provide sufficient detail to demonstrate how it arrived at a cost credit of only $0.98 per month. Additionally, Edison has failed to provide any clear information regarding the obvious savings to Edison that would result from customers selecting competitive metering services.

Q. What types of savings would you expect Edison to enjoy as a result of customers selecting competitive metering services.

A. Besides the direct savings in meter reading expenses, the savings to Edison should include:

- Meter maintenance that would not be required to be performed by Edison;
- Some meters that would be replaced by a competitive MSP and RES would be approaching the end of their service life. Edison would receive a cost saving by having these outdated meters replaced and paid for by someone else, yet these savings are not reflected in the proposed metering service charges;
- Some meters that would be replaced by MSPs would have been subjected to the cost of meter testing by Edison due to high bill complaints and service problems;
- A cost savings due to a reduction in "missed reads" and special reads;
- A reduction in the cost to Edison of responding to high bill complaints; and
- A savings of the cost to install a meter for a new customer.

Edison proposes a limited credit based upon some marginal cost savings. However, it appears that Edison proposes that customers who have switched to take metering services from an MSP should still continue to be charged by Edison for its return on investment (or implied profit) on its metering assets even though these customers receive no benefit from these assets.

Q. Do you have any other observations regarding Edison's proposed revisions to its standard metering charge?

A. Yes. Edison has not shown that customers who select alternative MSPs will not be charged for Edison's overhead costs for which such customers no longer benefit from. Edison has not shown that customers will not be charged for its operational and customer service management overhead, and tools and supplies that are no longer needed to serve the customer. Further, Edison proposes a cost credit of only $0.98 per month for all meters. While the cost of meters varies by customer size and maintenance costs, service charges can also vary by meter complexity and customer size. Therefore, a single metering service cost credit for all customer classes cannot be justified.

Q. Will Edison's proposed revision to its MSP credit facilitate customer choice?

A. Instead of promoting customer choice, Edison's proposed revision to its standard metering charge will amount to a barrier to competition. Edison's proposed revisions discourages competition by not giving appropriate and fair cost credits to customers who exercise choice in metering services and puts competing MSPs at an economic disadvantage. The proposed metering service charges would raise the net cost of MSPs to provide advanced metering services to customers and would deter customers and new competitors from building a competitive electric business in Illinois.

Q. Please describe the effect of Edison's proposal to virtually eliminate the SBO credit.

A. Edison has proposed to reduce the SBO credit to a mere 3 cents per month from the current 55 cents per month (*See* Edison Witnesses Alongi and Kelly, Edison Exhibits 13.0 at 46-47, Attachment O, 1 of 1). Edison manages to achieve this result by asking again for that which has been rejected multiple times, a supposed avoided cost analysis. Edison also repeats its assertion that since the Commission has prohibited Edison from forcing ARES utilizing the SBO to collect past due balances for bundled service, the credit should be reduced. The avoided cost argument is no more valid this time around than the last several times it has been made by Edison. And, Edison's original SBO credit was based on the original SBO tariff that never included the right to force ARES to collect past due bundled service balances in the first place. The effect is less the money than the principle. The Commission should not endorse Edison's notion that when it no longer performs a function it should still get paid for it; especially since the Commission has already been stalwart in rejecting Edison's misguided notion. Customers and competitors should not be penalized for finding better ways than those Edison has found to provide service.

The Commission should retain the current SBO credits and reject Edison's plan to virtually eliminate SBO credits.

Q. Please summarize your testimony.

A. The Edison filing is a two-fold threat to electric customers and to the Commission. It would have the effect of seriously undermining the progress of the past two years in achieving an open access environment and, once having gutted competition, this $575 million filing serves as a Trojan Horse for a major rate increase for all customers in 2005. By luring the Commission into accepting rate increases for the minority of customers who are on delivery services now, Edison would succeed in a pre-emptory strike and lock in hundreds of millions of dollars in general rate increases. Edison's plan is clear: destroy competition in the short term and saddle rate payers with enormous rate increases in the long term. If the Commission does not sever the proposed rate increases and other changes for the commercial and industrial customers from this filing as suggested in our testimony, the Commission must dramatically revise Edison's proposal so as to not undermine competition now and its own authority in the future to actually regulate rates for monopoly services in the future.

Q. Does this complete your testimony?

A. Yes.

A

ATTACHMENT A

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Dr. O'Connor is nationally recognized as an expert on the development and implementation of competitive strategies in regulated industries. He is a frequent speaker, both nationally and internationally, on utility and insurance issues and has authored numerous articles in professional trade journals. Prior to joining NewEnergy, he was a partner with Coopers & Lybrand Consulting, into which he had merged his own firm, Palmer Bellevue Corporation in, 1994. Previously, Dr. O'Connor served as Illinois' chief utility regulator, chairing the Illinois Commerce Commission, and served as Director of the Illinois Department of Insurance.

Employment:

Illinois Market Leader, AES NewEnergy, Inc. (1998-Present)

Principal/Partner, Coopers & Lybrand Consulting/Palmer Bellevue (1995-1998)

Managing Director, Palmer Bellevue, a Division of Coopers & Lybrand (1994-1995)

President and Chairman, Palmer Bellevue Corporation (1986-1993)

Chairman, Illinois Commerce Commission (1983 - 1985)
- Member, National Association of Regulatory Commissioners (1983-1985)

Director, Illinois Department of Insurance (1979 - 1982)
- Member, National Association of Insurance Commissioners (NAIC) (1979-82)

Assistant to the Director and Deputy Director for Research and Urban Affairs, Illinois Department of Insurance (1977 - 1979)

Administrative Assistant to U.S. Representative George Miller (7^{th}-CA) (1974-1977)

Assistant to California Senate Majority Leader, George Moscone (1973 - 1974)

Administrative Aide to Illinois Governor Richard B. Ogilvie (1969 - 1973)

ATTACHMENT A

Public and Political Service

Political Director, Citizens for Governor Thompson (1982)

Chairman, U.S. Environmental Protection Agency Allowance Tracking & Trading Subcommittee of the Acid Rain Advisory Committee (1991-1992)

General Chairman, Citizens for Governor Edgar (1994)

Chairman of the Illinois Health Care Reform Task Force (1993-1994)

Chairman of the Illinois Task Force on Human Services Consolidation (1996-1998)

Member, Illinois State Board of Elections (1998-Present)

Member, Children and Families Transition Committee to Governor-Elect George H. Ryan (1998)

Chairman, Interim Board of the Illinois Insurance Exchange (1998)

Education

1966 - 1968	University of San Francisco
1968 - 1969	Loyola University of Chicago, Rome Center for Liberal Arts
1969 - 1970	Loyola University of Chicago, A.B. *Magna cum laude*
1971	Northwestern University M.A. Political Science *Co-optation: A Re-definition and the Case of Chicago*
1979	Northwestern University, Ph.D. Political Science Dissertation: *Metrosim/A Computer Simulation Model of U.S. Urban Systems*

Academic

1997	Co-Instructor with Professor Alan Gitelson, *Money, Media, Message, Measurement & Motivation: Political Campaigns in the 90s*, an upper division undergraduate course in Political Science.
1997 & 1998	Instructor, *The Politics of Deregulation*, a five-week mini-course at the Kellogg Graduate School of Management at Northwestern University

B

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AES-NEWENERGY, (November/00-Present)
Director of Pricing & Product Development *Chicago, IL*

- Develop analytical tools and pricing models to assist the retail electric supply sales effort in the Illinois market. Our team has successfully signed more than 700MW of retail customer load with projected annual margins of over $9M during 2001 with the use of these tools. These pricing models take into account all aspects of the retail electric supply market and provide the flexibility necessary to be responsive to customer preferences, shifting market conditions and regulatory changes.
- Provide active leadership in the area of new product development in order to serve customers with complex requirements and to differentiate AES-NewEnergy in the marketplace. Our team has introduced an innovative curtailment program that is unique in the industry. We are concurrently deploying energy information systems (WebJoules), and energy systems services while refining and integrating these concepts to complement our electric supply business.
- Assist regulatory efforts affecting retail business plans. Issues such as reciprocity compliance and identification of impediments to retail access have been addressed in my current role.

ALLIANT ENERGY CORPORATION, (October/90 – November/00)
Alliant Energy Resources (Energy Planning)
Project Manager (January/98 – November/00) *Madison, WI*

- Provide project management and technical support for various strategic energy planning initiatives on behalf of our customers, e.g. market analysis, customer choice market opportunities, barriers to competition, commodity pricing, product opportunities, and integration concepts.
- Assist customers in a number of states across the nation in obtaining lower energy costs.
- Support department initiatives with proposal development and sales communications.
- Take an active role in the education of colleagues regarding the technical, regulatory and economic issues involved in a rapidly changing environment.
- Assist department director on development of synergy's between internal departments and customer requirements, e.g. Energy Applications, Energy Management, Gas Management, Capital Approval, Market Research, Cargill-Alliant and Schedin & Associates.
- Communicate with various customers groups and internal audiences concerning the changing nature of the energy business during this transitional period. Significant participation in the Illinois energy marketplace.

Alliant Utilities (IPC)
Consumer Services Coordinator (December/93 - January/98) *Albert Lea, MN*

- Lead department that implemented and delivered electric and natural gas energy conservation and demand side management programs in the southern Minnesota service territory (team of four). Superior levels of customer participation and department performance were attained.
- Employed numerous new technologies in the pursuit of success with a wide variety of customer requirements, e.g. lighting, motors, drives, chillers, controls, heat recovery and financing.
- Communicated with all customer groups in conjunction with marketing, operations, accounting, economic development and pricing issues.
- Served on business development task force and as chairman of standby generation subcommittee to initiate and analyze unregulated strategic initiatives.
- Participated on and contributed to the natural gas business development strategy team in an effort to enhance the profitability of business segment.
- Served on task force formed to formulate strategy in response to deficiencies noted by large customer survey.
- Implemented seasonal rate designs and identified and communicated with customers most affected.
- Developed and implemented geothermal business marketing efforts and introduced leasing programs to overcome first cost obstacles and to enhance profitability.
- Presented "Future of Utilities" and "Customer Choice" presentations to area service clubs and other organizations.

- Assisted concurrently as the *Industrial Representative* of the Decorah District and Coordinator in Albert Lea during merger process.

Alliant Utilities (IPC)
Industrial Representative (October/90 - December/93) *Clinton, IA*

- Implemented and promoted demand side management programs, particularly as they affected large commercial and industrial customers.
- Established new relationships with company's largest customers.
- Prepared numerous studies for industrial customers on wide variety of topics including; interruptible electric rate options, seasonal rate designs, time-of-use rate options, interruptible and transportation gas rate options, energy efficient lighting, energy efficient motors, adjustable speed drives, power factor improvement, power quality issues, energy management systems and cogeneration feasibility.
- Delivered over 200 presentations on utility business topics such as electromagnetic fields, harmonics, gas and electric safety, and economic development.
- Introduced transportation gas tariffs and optional purchasing scenarios to company's largest natural gas customers when industry became deregulated.

Marketing/ Engineering Experience

CATERPILLAR, INC., (January/88 - October/90)
Engine Division, Marketing Department, Marine Business Development
Application Engineer, (July/90 - October/90) *Peoria, IL*

- Worked in the Marine engine sales and product support department investigating competitive life-cycle costs, communicating with the company's dealers on establishing proper pricing levels, and analyzing worldwide parts sales.
- Tested and modified commercial software for use in specifying the company's equipment and presented final version to users and customers.

Engine Division, Marketing Department, Electrical Power Generation Group
Application Engineer, (January/88 - July/90) *Peoria, IL*

- Prepared slide presentation and speech covering Engine Division's product marketing strategy. Presentation was delivered worldwide by product marketing manager and was distributed to representatives in all subsidiaries.
- Delivered technical product presentations to dealer personnel and consulting engineers in Peoria and at seminars across the country.
- Wrote special engineering quotations for generator set arrangements and attachments.
- Analyzed engine and generator testing facilities at company's technical center. Prepared instructional documentation for users of these facilities.

Engineering Experience

ACCURATE METERING SYSTEMS, INC., *Schaumburg, IL*
Project Engineer, (Internship, Summer - 1987)

MCDONNELL-DOUGLAS AIRCRAFT COMPANY, *St. Louis, MO*
Project Engineer, (Internship, Summer - 1986)

RANDOLPH AND ASSOCIATES, *Peoria, IL*
Engineering Assistant, (Part Time, December/85 - January/87)

Education

Master of Business Administration, July 1990
Bradley University, Peoria, Illinois G.P.A. 3.91/4.00
Bachelor of Science in Electrical Engineering, December 1987
Bradley University, Peoria, Illinois G.P.A. 3.24/4.00
Licensed Professional Engineer (Electrical) - Illinois and Minnesota
Certified Energy Manager (CEM)

APPENDIX 1

THIS DOCUMENT CONTAINS
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APPENDIX 1

METHODOLOGY UTILIZED FOR AES NEWENERGY ANALYSIS

This appendix will explain the methodology utilized by AES NewEnergy in its analysis. Specifically, this appendix will explain:

- Customer Account Selection Process;
- Customer Account Usage Data;
- Definition of Annual Load Factor Subclasses;
- Selection Of Specific Customer Accounts From Sub-Classes;
- Method of Analysis;
- Baseline Results;
- Estimated Annual Savings Increases/(Decreases);
- Transmission Charge Sensitivity Analysis; and
- Market Value Sensitivity Analysis.

Customer Account Selection Process

As of early July 2001, AES NewEnergy served electric energy to a total of customer accounts in the Edison service territory. In order to determine an appropriate group of specific customers, who would best represent a cross-section of AES NewEnergy's entire customer base, the customer accounts were segmented by RCDS Customer Class and by annual load factor. In addition to the RCDS Customer Class segmentation, three other specific segments possessing unique characteristics differing from the overall group of customer accounts were established. These three specific segments are identified as the Space Heat, IRMA member, and HVDS segments.

The *Space Heat* segment is defined as including those customer accounts who would normally receive a class determined CTC when choosing delivery services, but instead receive the Rider 25 class CTC (which is currently 0 for Period A) because of their former bundled rate incorporation of Rider 25. Additionally, the Space Heat segment is further defined by the type of pricing arrangement these customer accounts receive from AES NewEnergy. Each customer account in this segment receives pricing in its contract with AES NewEnergy that is a function of their former bundled rates including the Rider 25 component. It should be noted that several other customer accounts served by AES NewEnergy might have utilized Rider 25 when they were served by Edison on bundled rates. However, these customer accounts are not included in the Space Heat segment as their pricing arrangement with AES NewEnergy is not a function of their former bundled rates, including the Rider 25 component.

The *IRMA* segment is defined as including those customer accounts that again would normally receive a Class CTC but instead receive a Custom CTC calculation (as would a large customer with usage greater than 3,000 kW) due to a special provision of the Customer Choice Act.

The *HVDS* segment is defined as including those customer accounts that are currently eligible for Rider 11- High Voltage Discount who would become eligible for the newly proposed Rider HVDS - High Voltage Discount.

Each of these three additional segments has a unique situation as it relates to this delivery services *tariff* proceeding and therefore has been identified for analysis as a separate customer account category. In fact, the two HVDS subclasses (representing customer accounts) has been separately compared to the current delivery services tariffs.

Customer Account Usage Data

The customer account usage data was extracted from a variety of sources. Primarily, AES NewEnergy's internal billing, accounting, and pricing data sources were utilized in obtaining the majority of the usage information. In some circumstances, the usage data was supplemented with information from the Edison PowerPath website.

Definition of Annual Load Factor Subclasses

For purposes of this analysis the annual load factor is defined as a function of the maximum annual billing demand instead of the maximum annual peak demand which may or may not occur within the defined billing demand time window. Therefore, the formula used to determine each customer account's annual billing demand load factor ("Billing Load Factor") is = Annual kWh/(Maximum Annual Billing Demand kW x 8760).

From this definition, the AES NewEnergy customer accounts were distributed into the following sub-classes within each customer account class:

Subclass A: 0% < Billing Load Factor <=15%
Subclass B: 15% < Billing Load Factor <=30%
Subclass C: 30% < Billing Load Factor <= 45%
Subclass D: 45% < Billing Load Factor <= 60%
Subclass E: 60% < Billing Load Factor <= 75%
Subclass F: 75% < Billing Load Factor

By way of example, if a customer account is identified as an RCDS Class 7 and this customer account's usage data establishes a Billing Load Factor of 50%, then that customer account would be classified as a "7D". All customer accounts were categorized based on these criteria. Table 1 shows the spectrum of AES NewEnergy's customer base used for this analysis as of July, 2001.

Selection Of Specific Customer Accounts From Sub-Classes

In order to represent the sub-class in the most accurate manner, the customer account whose Billing Load Factor was closest to the mid-point of the sub-class definition range was selected. By way of example, the "B" defined sub-class range has a mid-point of 22.5%. The customer account in sub-class 5B, which has a Billing Load Factor that most closely approaches 22.5%, is an account with a Billing Load Factor of 22.1%. This account was selected to represent the customer accounts that reside in sub-class 5B. In a similar manner, this same approach was used in order to identify the proper customer accounts to use in this analysis.

Several special situations occurred during the customer account selection process. First, all customer accounts in sub-class 3D and customer accounts in sub-class 3E are members of IRMA and benefit from the custom CTC calculation described above. Therefore, we decided to utilize the respective sub-classes 3D and 3E customer accounts to represent the unique economic situation presented by this circumstance.

Additionally, the single (1) customer account in sub-class 2D and the two (2) customer accounts in sub-class 4F are also IRMA members. These customer account sub-classes were <u>not</u> selected individually for further analysis as the 3D and 3E customer accounts (respectively) were regarded as representative of the economic situation presented by the IRMA custom CTC arrangement.

Finally, it should be noted that in a couple of other sub-classes, the customer account whose Billing Load Factor most closely approached the mid-point of the defined range happened to be another IRMA member. In these cases, the customer account with the closest Billing Load Factor to the mid-point who was <u>not</u> an IRMA member was selected instead. This was done to more closely demonstrate the effects on the more typical customers in these sub-classes who do receive the class defined CTC's as opposed to the IRMA members who receive the benefit of custom CTC calculations and are already represented by the analysis of the 3D and 3E customer accounts analysis.

Method of Analysis

The bundled rate for each selected customer account was determined based on the appropriate bundled rate class for the account if the customer account were to return to bundled service. The respective bundled rates chosen for comparative purposes are shown in Table 2. In the case of the two (2) customer accounts analyzed in the HVDS sub-classes (HVDS-E and HVDS-F), the Rate 6L bundled calculation includes the addition of Rider 11 (High Voltage Discount) which is currently in effect. In the case of the three (3) Space Heat customer accounts analyzed (SH-B, SH-C, and SH-D), the provisions of Rider 25 were also taken into consideration for the bundled rate calculation.

The current delivery services tariff economics were evaluated using the existing delivery services tariffs and rates, the current PPO Period A MVEC's, the current Period A CTC's, and the current PPO transmission charges for each of the respective customer accounts selected for evaluation. All analysis performed was based on a 12-month period. The cost components that comprise the PPO were selected as a comparative and familiar benchmark as a measurement of how the proposed delivery services tariff changes will affect customers who have chosen delivery services rates rather than bundled rates.

Market Values

The market values derived by Edison as shown in Exhibit 13 – Attachment F were used in this analysis. It is my understanding that these MVEC's (which are slightly lower than the current Period A MVEC's) are based on the same set of "market snapshots" that were used to create the current Period A MVEC's that are now in effect.

Customer Transition Charges

The class CTC's produced by Edison in Exhibit 13 – Attachment G were used in this comparative analysis.

Selected customer accounts were submitted to the Edison Rate Department for determination of Custom CTC values based on the *proposed* delivery services tariff rates and costs.

Transmission Charges

This analysis utilized the 0.230¢ per kWh for transmission charges that were utilized by Edison witnesses Alongi/Kelly in ComEd Exhibit 13 – Attachment E. This is the same figure used by Edison for transmission costs in the derivation of the class and custom CTC derivations.

It should be observed at this point that the transmission charge of 0.230¢ per kWh used in the proposed delivery services tariffs analysis by Edison does not vary by class, as do the current

PPO transmission charges. More importantly, in all cases (except for RCDS Class 10), this assumed transmission cost is lower than the current transmission charges assigned to customers who choose to be served by the PPO. Table 3 illustrates these differences.

AES NewEnergy's concern is that if Edison's assumption of decreasing transmission charges does not materialize as suggested in Edison's calculations, then the effect of increasing delivery services tariffs will have been understated in this proceeding since the assumed lower transmission charges tend to "shield" or "lessen" the effect of the proposed increases in the delivery charges included in Edison's figures.

Baseline Results

The baseline set of comparisons is between the current cost components of the PPO as compared to those same cost components in the proposed delivery services tariffs. Table 4A (and its corresponding summary line on Table 6) shows this comparison.

Estimated Annual Savings Increases/(Decreases)

These amounts were estimated by multiplying the total annual kWh in each respective sub-class by the cost increase in cents per kWh for the sample customer account selected to represent that sub-class. For example, the specific customer account selected in sub-class 6C would experience an increase in total costs of 0.26889¢ per kWh. Sub-class 6C in its entirety utilizes kWh of annual energy consumption. Therefore, the total increased cost assumed for that portion of AES NewEnergy's customer base for sub-class 6C is X 0.26889¢ = $.

The results of the initial run indicate that (%) of AES NewEnergy's present customer accounts, excluding the HVDS-eligible accounts, would be adversely affected (savings would diminish under the proposed delivery services tariffs.) Those same customer accounts comprise % of AES NewEnergy's annual sales volume, excluding the 4 HVDS-eligible accounts. In addition, if a comparison is made between the total amount of annual cost *increases* compared to total amount of estimated annual cost *decreases* across the AES NewEnergy customer base, excluding the HVDS-eligible accounts, there is a **net cost increase of $2,454,482** ($3,753,733 - $1,299,251). The results of this analysis appear to conflict with the assertions in Edison witness Juracek's testimony concerning the ability of CTC decreases to offset the proposed increases in delivery services charges.

The top row of Table 6 summarizes the results of the baseline analysis and includes the following:

- an estimate of how many customer accounts would see savings diminish compared to bundled rates under the proposed delivery services tariffs;
- the proportion of load these accounts represent of AES NewEnergy's customer base, excluding the HVDS-eligible accounts;
- the estimated dollar increase in annual cost; and
- how many of these customer accounts would be expected to become more economically served under bundled rates as a consequence.

<u>**Transmission Charge Sensitivity Analysis**</u>

As Edison doesn't adequately defend or justify its assumption that transmission charges will decrease, a more reasonable assumption is that transmission charges will remain the same. Table 4A shows that in all sub-classes, except those in RCDS Class 10, Edison's estimated transmission charge of 0.230¢ per kWh for each respective sub-class, results in a presumed decrease in costs due to lower transmission charges than are currently in effect. In fact, if one considers the customer account representative of the 3D-IRMA sub-class, the result of Edison's assumed decrease in transmission rates resulted in this group being considered to have a savings *increase* rather than a savings *decrease*. In many other sub-classes, the presumed decrease in transmission charges tended to "shield" or "lessen" the total effect of the increase in delivery services charges in the proposed tariffs.

To examine the more reasonable assumption that transmission charges remain at their current level, the analysis in Table 4B (and its corresponding summary line on Table 6) was produced. This analysis was performed in a similar manner except that transmission charges were assumed to remain unchanged from their present levels. The fact that the CTC would have been further reduced in the cases where the CTC had enough "room" to absorb this change was also taken into account. For example, consider the customer account representative of sub-class 5B as listed on Tables 4A and 4B. One can see that if that customer account's transmission cost does not decrease by $614 (Table 4A) that the expected CTC for this customer account will improve from a decrease of $1,540 (Table 4A) to a decrease of $1,824 (Table 4B). However, since the customer's CTC cannot go below zero, this decrease is not sufficient to prevent an additional increase in total annual cost under the proposed delivery services tariffs should transmission charges remain unchanged. In this example the customer account would experience a total additional annual increase in cost of $330. In other words, the CTC can only "absorb" *some* of the cost should transmission charges remain level rather than decrease as Edison's testimony asserts.

In the case of customer accounts in classes that have zero or near zero CTC's (RCDS classes 6 and above), the "level" transmission charge cannot be offset by a corresponding decrease in CTC since the CTC is already near or at the minimum. Therefore, if transmission costs remain level, delivery services customers will experience even greater savings reductions. Let me emphasize that this testimony is not suggesting that there will be an increase in transmission charges relative to present day costs, this analysis simply studies the impact of this filing if Edison's assumption that transmission costs will decline does not materialize and instead those costs remain where they are today. Should transmission charges actually *increase* from present day levels, this would have an even further detrimental effect on the competitive market in which AES NewEnergy operates.

Table 4B (and its corresponding summary line in Table 6) demonstrates the effects should transmission charges remain unchanged while adjusting the corresponding CTC's accordingly. One difference found in this analysis is that all the IRMA customers represented by the customer account in sub-class 3D move from experiencing an increase in annual savings to a decrease in annual savings when this difference is taken into account. The other significant difference found should transmission charges remain level is that the **total increased cost** for the proposed delivery services charges on the AES NewEnergy customer base, excluding the 4 HVDS-eligible accounts, would **grow by over $767,000 annually** to $3,222,288 ($4,261,534 - $1,039,247.) (*See* Chart C and Table 6.)

Market Value Sensitivity Analysis

In order to assess the impacts of increasing MVEC's in combination with the proposed increases in delivery services tariffs, the analyses provided in Tables 5A and 5B and 5C were produced. Each of these tables also has a corresponding summary line shown in Table 6. Tables 5A and 5B display the effect of a 5% increase in MVEC's for both the present and proposed delivery services tariffs respectively, along with the corresponding effects on CTC's. Likewise, Table 5C shows the same +5% MVEC scenario utilizing the proposed delivery services tariffs and level transmission charges rather than decreasing ones.

Should MVEC's rise as little as 5% from their current levels the effects on AES NewEnergy's customer base would be harmful even if the delivery services tariffs remain unchanged. However, the effects of an increase in MVEC's of 5% are even more pronounced if considered in *combination* with the proposed increase in delivery services tariffs.

For example, Table 5A (and its corresponding summary line in Table 6) indicate that should MVEC's rise by 5% from current levels, than more than half of AES NewEnergy's customer accounts, excluding the 4 HVDS-eligible accounts, would experience an **increase in cost of approximately $4.7 M** ($4,705,290 - $9,591.) On average, those customer accounts that would see this increase would see total annual costs rise by 1.7%. In contrast, Table 5B (and its corresponding summary line in Table 6) demonstrates the effects of a 5% increase in market values in combination with the proposed increase in delivery services tariffs. These results indicate a **88.5% *larger* annual cost increase of $8.857M** ($9,110,815-$253,640.) due to a 5% increase in MVECs based upon the rates in the current delivery services tariffs. On average, those customer accounts that would see this increase would see total annual costs rise by 4.9%. Table 5C (and its corresponding summary line in Table 6) demonstrates the effects of a 5% increase in market values in combination with the proposed rate changes in the delivery services tariffs while keeping transmission charges level. These results indicate a **112.7% *larger* annual cost increase of approximately $10M** ($10,069,604 - $77,314.) On average, those customer accounts that would see this increase would see total annual costs rise by 5.7%. Finally, the analysis indicates that many more customers representing a much large share of AES NewEnergy's customer base and sales volume would become more economically served under bundled rates should a 5% MVEC increase occur in combination with the proposed increase in delivery services tariffs. (*See* Table 6 and Charts D and E.)

Table 1: NewEnergy Customer Base Analysis

	Annual Billing Demand Load Factor > than LF	Annual Billing Demand Load Factor <= LF	Customer Accounts Analyzed
Class 2A Customer Accounts	0%	15%	0
Class 2B Customer Accounts	15%	30%	1
Class 2C Customer Accounts	30%	45%	0
Class 2D Customer Accounts-IRMA	45%	60%	0
Class 2E Customer Accounts	60%	75%	0
Class 2F Customer Accounts	75%	N/A	0
Class 3A Customer Accounts	0%	15%	1
Class 3B Customer Accounts	15%	30%	1
Class 3C Customer Accounts	30%	45%	1
Class 3D Customer Accounts-IRMA	45%	60%	1
Class 3E Customer Accounts-IRMA	60%	75%	1
Class 3F Customer Accounts	75%	N/A	1
Class 4A Customer Accounts	0%	15%	1
Class 4B Customer Accounts	15%	30%	1
Class 4C Customer Accounts	30%	45%	1
Class 4D Customer Accounts	45%	60%	1
Class 4E Customer Accounts	60%	75%	1
Class 4F Customer Accounts-IRMA	75%	N/A	0
Class 5A Customer Accounts	0%	15%	0
Class 5B Customer Accounts	15%	30%	1
Class 5C Customer Accounts	30%	45%	1
Class 5D Customer Accounts	45%	60%	1
Class 5E Customer Accounts	60%	75%	1
Class 5F Customer Accounts	75%	N/A	1
Class 6A Customer Accounts	0%	15%	0
Class 6B Customer Accounts	15%	30%	1
Class 6C Customer Accounts	30%	45%	1
Class 6D Customer Accounts	45%	60%	1
Class 6E Customer Accounts	60%	75%	1
Class 6F Customer Accounts	75%	N/A	0
Class 7A Customer Accounts	0%	15%	0
Class 7B Customer Accounts	15%	30%	1
Class 7C Customer Accounts	30%	45%	1
Class 7D Customer Accounts	45%	60%	1
Class 7E Customer Accounts	60%	75%	1
Class 7F Customer Accounts	75%	N/A	1
Class 8A Customer Accounts	0%	15%	0
Class 8B Customer Accounts	15%	30%	0
Class 8C Customer Accounts	30%	45%	1
Class 8D Customer Accounts	45%	60%	1
Class 8E Customer Accounts	60%	75%	1
Class 8F Customer Accounts	75%	N/A	1
Class 9A Customer Accounts	0%	15%	0
Class 9B Customer Accounts	15%	30%	0
Class 9C Customer Accounts	30%	45%	1
Class 9D Customer Accounts	45%	60%	1
Class 9E Customer Accounts	60%	75%	1
Class 9F Customer Accounts	75%	N/A	0
Class 10A Customer Accounts	0%	15%	0

Class 10B Customer Accounts	15%	30%	1
Class 10C Customer Accounts	30%	45%	0
Class 10D Customer Accounts	45%	60%	1
Class 10E Customer Accounts	60%	75%	1
Class 10F Customer Accounts	75%	N/A	0
Class HVDS-A Customer Accounts	0%	15%	0
Class HVDS-B Customer Accounts	15%	30%	0
Class HVDS-C Customer Accounts	30%	45%	0
Class HVDS-D Customer Accounts	45%	60%	0
Class HVDS-E Customer Accounts	60%	75%	1
Class HVDS-F Customer Accounts	75%	N/A	1
Class S.H.-A Customer Accounts	0%	15%	0
Class S.H.-B Customer Accounts	15%	30%	1
Class S.H.-C Customer Accounts	30%	45%	1
Class S.H.-D Customer Accounts	45%	60%	1
Class S.H.-E Customer Accounts	60%	75%	0
Class S.H.-F Customer Accounts	75%	N/A	0

Table 2: Bundled Rates and RCDS Classes for Selected Customer Accounts

Customer Name	Comparable Bundled Rate	RCDS Class	ABDLF %	Annual kWh
2B	6NTOD-D	2	22.6%	30,620
3A	6NTOD-D	3	10.1%	85,580
3B	6NTOD-D	3	22.0%	97,260
3C	6NTOD-D	3	37.8%	236,069
3D-IRMA	6NTOD-D	3	53.4%	339,480
3E-IRMA	6NTOD-D	3	64.4%	268,801
3F	6NTOD-D	3	80.9%	467,520
4A	6NTOD-D	4	6.1%	142,013
4B	6NTOD-D	4	22.5%	358,812
4C	6NTOD-D	4	37.4%	1,250,160
4D	6NTOD-D	4	51.9%	598,220
4E	6NTOD-D	4	64.2%	1,150,140
5B	6TOD	5	22.1%	944,880
5C	6TOD	5	37.5%	1,637,581
5D	6TOD	5	52.6%	3,569,165
5E	6TOD	5	66.5%	3,596,078
5F	6TOD	5	75.9%	4,300,351
6B	6TOD	6	24.1%	2,007,821
6C	6TOD	6	36.9%	3,223,343
6D	6TOD	6	51.1%	3,647,189
6E	6TOD	6	72.1%	5,879,323
7B	6L	7	22.0%	2,668,046
7C	6L	7	38.0%	6,799,080
7D	6L	7	50.3%	9,226,443
7E	6L	7	67.5%	16,658,118
7F	6L	7	76.0%	7,297,748
8C	6L	8	40.1%	14,232,857
8D	6L	8	53.2%	23,735,835
8E	6L	8	68.3%	32,258,786
8F	6L	8	82.9%	30,856,560
9C	6L	9	43.0%	29,313,540
9D	6L	9	50.6%	28,388,480
9E	6L	9	64.3%	44,594,607
10B	6L	10	24.9%	53,510,526
10D	6L	10	52.5%	62,090,243
10E	6L	10	67.7%	68,003,885
SH-B	6NTOD-D-SH	3	21.9%	105,730
SH-C	6NTOD-D-SH	4	30.9%	527,920
SH-D	6NTOD-D-SH	4	51.6%	1,748,114
HVDS-E	6L-R11	10	65.0%	104,639,884
HVDS-F	6L-R11	9	82.2%	51,632,814

Table 3: Transmission Cost Comparison

RCDS Class #	Current PPO Transmission Charges	Transmission Charges Used by ComEd in this Proceeding	Difference	
1	0.289	0.230	0.059	¢/kWh
2	0.344	0.230	0.114	¢/kWh
3	0.343	0.230	0.113	¢/kWh
4	0.320	0.230	0.090	¢/kWh
5	0.295	0.230	0.065	¢/kWh
6	0.292	0.230	0.062	¢/kWh
7	0.272	0.230	0.042	¢/kWh
8	0.267	0.230	0.037	¢/kWh
9	0.260	0.230	0.030	¢/kWh
10	0.228	0.230	(0.002)	¢/kWh

Table 4A: Comparison of Current PPO Components to Proposed PPO Components for Selected Customer Accounts

Customer Name	Change in Annual DST Costs	Change in Annual Transmission Costs	Change in Annual CTC Costs	Change in Annual PPO Energy Costs	Change in Annual Total PPO Costs	PPO Savings Diminish?	Bundled Rate Becomes More Economic?
2B	$245	($35)	($177)	($8)	$26	Yes	No
3A	$1,668	($97)	($364)	($33)	$1,175	Yes	No
3B	$575	($110)	($413)	($38)	$14	Yes	No
3C	$585	($267)	($1,003)	($91)	($776)	No	No
3D-IRMA	$356	($384)	$0	($131)	($159)	No	No
3E-IRMA	$489	($304)	$0	($102)	$83	Yes	No
3F	$372	($528)	($1,987)	($180)	($2,323)	No	No
4A	$8,775	($128)	($392)	($24)	$8,231	Yes	Yes
4B	$2,060	($323)	($990)	($60)	$687	Yes	No
4C	$2,099	($1,125)	($3,450)	($208)	($2,684)	No	No
4D	$987	($538)	($1,651)	($99)	($1,302)	No	No
4E	$1,440	($1,035)	($3,174)	($194)	($2,964)	No	No
5B	$3,254	($614)	($1,540)	($338)	$761	Yes	No
5C	$1,665	($1,064)	($2,669)	($554)	($2,623)	No	No
5D	$4,656	($2,320)	($5,818)	($1,162)	($4,644)	No	No
5E	$1,757	($2,337)	($5,862)	($1,096)	($7,538)	No	No
5F	($554)	($2,795)	($7,010)	($1,331)	($11,689)	No	No
6B	$17,487	($1,245)	($2,891)	($297)	$13,055	Yes	No
6C	$15,875	($1,998)	($4,642)	($567)	$8,667	Yes	No
6D	$3,712	($2,261)	($5,252)	($595)	($4,397)	No	No
6E	$6,040	($3,645)	($8,466)	($945)	($7,017)	No	No
[illegible]	$9,975	($1,121)	($3,815)	($640)	$4,399	Yes	No
7C	$25,132	($2,856)	($9,723)	($1,726)	$10,827	Yes	No
7D	$27,071	($3,875)	($13,194)	($2,105)	$7,897	Yes	No
7E	$9,146	($6,996)	($23,821)	($3,751)	($25,423)	No	No
7F	$3,828	($3,065)	($10,436)	($1,485)	($11,158)	No	No
8C	$37,135	($5,266)	$0	($2,342)	$29,527	Yes	No
8D	$30,719	($8,782)	$0	($3,780)	$18,157	Yes	No
8E	$22,269	($11,936)	$0	($5,057)	$5,275	Yes	No
8F	$1,148	($11,417)	$0	($4,787)	($15,056)	No	No
9C	$77,973	($8,794)	$0	($4,742)	$64,437	Yes	No
9D	$53,682	($8,517)	($17,317)	($4,842)	$23,006	Yes	No
9E	$13,324	($13,378)	$15,608	($7,284)	$8,270	Yes	No
10B	$610,109	$1,070	($3,478)	($8,765)	$598,935	Yes	Yes
10D	$211,405	$1,242	$0	($9,556)	$203,092	Yes	No
10E	$186,797	$1,360	($17,001)	($10,095)	$161,061	Yes	No
SH-B	$561	($119)	$0	($41)	$401	Yes	No
SH-C	$1,379	($475)	$0	($89)	$815	Yes	No
SH-D	$2,072	($1,573)	$0	($291)	$208	Yes	No
HVDS-E	($271,456)	$2,093	$0	($15,664)	($285,027)	No	No
HVDS-F	($207,669)	($15,490)	$0	($7,490)	($230,649)	No	No

Table 4B: Comparison of Current PPO Components to Proposed PPO Components (w/ current transmission costs) for Selected Customer Accounts

Customer Name	Change in Annual DST Costs	Change in Annual Transmission Costs	Change in Annual CTC Costs	Change in Annual PPO Energy Costs	Change in Annual Total PPO Costs	PPO Savings Diminish?	Bundled Rate Becomes More Economic?
2B	$245	$0	($212)	($8)	$26	Yes	No
3A	$1,668	$0	($460)	($33)	$1,175	Yes	No
3B	$575	$0	($523)	($38)	$14	Yes	No
3C	$585	$0	($1,270)	($91)	($776)	No	No
3D-IRMA	$356	$0	$0	($131)	$224	Yes	No
3E-IRMA	$489	$0	$0	($102)	$387	Yes	No
3F	$372	$0	($2,515)	($180)	($2,323)	No	No
4A	$8,775	$0	($520)	($24)	$8,231	Yes	Yes
4B	$2,060	$0	($1,313)	($60)	$687	Yes	No
4C	$2,099	$0	($4,576)	($208)	($2,684)	No	No
4D	$987	$0	($2,189)	($99)	($1,302)	No	No
4E	$1,440	$0	($4,210)	($194)	($2,964)	No	No
5B	$3,254	$0	($1,824)	($338)	$1,092	Yes	No
5C	$1,665	$0	($3,161)	($554)	($2,050)	No	No
5D	$4,656	$0	($6,888)	($1,162)	($3,395)	No	No
5E	$1,757	$0	($6,940)	($1,096)	($6,279)	No	No
5F	($554)	$0	($8,300)	($1,331)	($10,184)	No	No
6B	$17,487	$0	($2,891)	($297)	$14,300	Yes	No
6C	$15,875	$0	($4,642)	($567)	$10,666	Yes	No
6D	$3,712	$0	($5,252)	($595)	($2,135)	No	No
6E	$6,040	$0	($8,466)	($945)	($3,372)	No	No
7B	$9,975	$0	($3,815)	($640)	$5,520	Yes	No
[illegible]	$25,132	$0	($9,723)	($1,726)	$13,683	Yes	No
7D	$27,071	$0	($13,194)	($2,105)	$11,773	Yes	No
7E	$9,146	$0	($23,821)	($3,751)	($18,426)	No	No
7F	$3,828	$0	($10,436)	($1,485)	($8,093)	No	No
8C	$37,135	$0	$0	($2,342)	$34,793	Yes	No
8D	$30,719	$0	$0	($3,780)	$26,939	Yes	No
8E	$22,269	$0	$0	($5,057)	$17,211	Yes	No
8F	$1,148	$0	$0	($4,787)	($3,639)	No	No
9C	$77,973	$0	$0	($4,742)	$73,231	Yes	No
9D	$53,682	$0	($25,834)	($4,842)	$23,006	Yes	No
9E	$13,324	$0	$2,230	($7,284)	$8,270	Yes	No
10B	$610,109	$0	($2,408)	($8,765)	$598,935	Yes	Yes
10D	$211,405	$0	$0	($9,556)	$201,850	Yes	No
10E	$186,797	$0	($17,001)	($10,095)	$159,701	Yes	No
SH-B	$561	$0	$0	($41)	$520	Yes	No
SH-C	$1,379	$0	$0	($89)	$1,290	Yes	No
SH-D	$2,072	$0	$0	($291)	$1,782	Yes	Yes
HVDS-E	($271,456)	$0	$0	($15,664)	($287,120)	No	No
HVDS-F	($207,669)	$0	$0	($7,490)	($215,160)	No	No

Table 5A: Comparison of Current PPO Components to Current Proposed PPO Components (MVEC +5%) for Selected Customer Accounts

Customer Name	Change in Annual DST Costs	Change in Annual Transmission Costs	Change in Annual CTC Costs	Change in Annual PPO Energy Costs	Change in Annual Total PPO Costs	PPO Savings Diminish?	Bundled Rate Becomes More Economic?
2B	$0	$0	($80)	$74	($6)	No	No
3A	$0	$0	($219)	$218	($1)	No	No
3B	$0	$0	($249)	$249	$0	Yes	No
3C	$0	$0	($605)	$599	($6)	No	No
3D-IRMA	$0	$0	$0	$869	$869	Yes	No
3E-IRMA	$0	$0	$0	$669	$669	Yes	No
3F	$0	$0	($1,199)	$1,183	($16)	No	No
4A	$0	$0	($359)	$339	($20)	No	No
4B	$0	$0	($907)	$876	($31)	No	No
4C	$0	$0	($3,159)	$3,122	($37)	No	No
4D	$0	$0	($1,511)	$1,502	($10)	No	No
4E	$0	$0	($2,906)	$2,773	($133)	No	No
5B	$0	$0	($1,824)	$2,506	$682	Yes	No
5C	$0	$0	($3,161)	$4,160	$999	Yes	No
5D	$0	$0	($6,888)	$8,739	$1,850	Yes	No
5E	$0	$0	($6,940)	$8,101	$1,160	Yes	No
5F	$0	$0	($8,300)	$9,783	$1,483	Yes	No
6B	$0	$0	($2,891)	$5,252	$2,361	Yes	No
6C	$0	$0	($4,642)	$7,659	$3,018	Yes	No
6D	$0	$0	($5,252)	$9,339	$4,087	Yes	No
6E	$0	$0	($8,466)	$13,713	$5,247	Yes	No
7B	$0	$0	($3,815)	$6,866	$3,051	Yes	No
[illegible]	$0	$0	($9,723)	$17,953	$8,230	Yes	No
7D	$0	$0	($13,194)	$22,037	$8,843	Yes	No
7E	$0	$0	($23,821)	$39,655	$15,834	Yes	No
7F	$0	$0	($10,436)	$15,988	$5,553	Yes	No
8C	$0	$0	$0	$35,202	$35,202	Yes	No
8D	$0	$0	$0	$55,835	$55,835	Yes	No
8E	$0	$0	$0	$74,298	$74,298	Yes	No
8F	$0	$0	$0	$68,684	$68,684	Yes	No
9C	$0	$0	$0	$70,159	$70,159	Yes	No
9D	$0	$0	($30,943)	$70,128	$39,184	Yes	No
9E	$0	$0	($58,865)	$106,621	$47,756	Yes	No
10B	$0	$0	($2,408)	$135,311	$132,903	Yes	No
10D	$0	$0	$0	$147,657	$147,657	Yes	No
10E	$0	$0	($17,001)	$154,113	$137,112	Yes	No
SH-B	$0	$0	$0	$269	$269	Yes	No
SH-C	$0	$0	$0	$1,279	$1,279	Yes	No
SH-D	$0	$0	$0	$4,357	$4,357	Yes	Yes
HVDS-E	$0	$0	$0	$240,722	$240,722	Yes	No
HVDS-F	$0	$0	$0	$111,416	$111,416	Yes	No

Table 5B: Comparison of Current PPO Components to Proposed PPO Components (MVEC +5%) for Selected Customer Accounts

Customer Name	Change in Annual DST Costs	Change in Annual Transmission Costs	Change in Annual CTC Costs	Change in Annual PPO Energy Costs	Change in Annual Total PPO Costs	PPO Savings Diminish?	Bundled Rate Becomes More Economic?
2B	$245	($35)	($256)	$66	$20	Yes	No
3A	$1,668	($97)	($582)	$184	$1,174	Yes	No
3B	$575	($110)	($661)	$210	$14	Yes	No
3C	$585	($267)	($1,604)	$504	($782)	No	No
3D-IRMA	$356	($384)	$0	$731	$703	Yes	No
3E-IRMA	$489	($304)	$0	$562	$748	Yes	Yes
3F	$372	($528)	($3,177)	$995	($2,338)	No	No
4A	$8,775	($128)	($587)	$314	$8,374	Yes	Yes
4B	$2,060	($323)	($1,482)	$812	$1,068	Yes	No
4C	$2,099	($1,125)	($5,163)	$2,903	($1,286)	No	No
4D	$987	($538)	($2,471)	$1,397	($625)	No	No
4E	$1,440	($1,035)	($4,750)	$2,570	($1,776)	No	No
5B	$3,254	($614)	($1,824)	$2,151	$2,966	Yes	No
5C	$1,665	($1,064)	($3,161)	$3,578	$1,018	Yes	No
5D	$4,656	($2,320)	($6,888)	$7,518	$2,966	Yes	No
5E	$1,757	($2,337)	($6,940)	$6,950	($571)	No	No
5F	($554)	($2,795)	($8,300)	$8,386	($3,263)	No	No
6B	$17,487	($1,245)	($2,891)	$4,941	$18,292	Yes	No
6C	$15,875	($1,998)	($4,642)	$7,063	$16,298	Yes	No
6D	$3,712	($2,261)	($5,252)	$8,714	$4,912	Yes	No
6E	$6,040	($3,645)	($8,466)	$12,720	$6,649	Yes	No
[illegible]	$9,975	($1,121)	($3,815)	$6,194	$11,233	Yes	No
[illegible]	$25,132	($2,856)	($9,723)	$16,140	$28,694	Yes	No
7D	$27,071	($3,875)	($13,194)	$19,827	$29,829	Yes	Yes
7E	$9,146	($6,996)	($23,821)	$35,717	$14,045	Yes	No
7F	$3,828	($3,065)	($10,436)	$14,429	$4,756	Yes	No
8C	$37,135	($5,266)	$0	$32,743	$64,612	Yes	No
8D	$30,719	($8,782)	$0	$51,866	$73,803	Yes	No
8E	$22,269	($11,936)	$0	$68,987	$79,320	Yes	Yes
8F	$1,148	($11,417)	$0	$63,658	$53,389	Yes	No
9C	$77,973	($8,794)	$0	$65,180	$134,360	Yes	No
9D	$53,682	($8,517)	($30,943)	$65,043	$79,265	Yes	No
9E	$13,324	($13,378)	($58,865)	$98,973	$40,053	Yes	No
10B	$610,109	$1,070	($6,154)	$126,107	$731,132	Yes	Yes
10D	$211,405	$1,242	$0	$137,623	$350,271	Yes	No
10E	$186,797	$1,360	($17,001)	$143,513	$314,669	Yes	No
SH-B	$561	($119)	$0	$226	$668	Yes	No
SH-C	$1,379	($475)	$0	$1,186	$2,090	Yes	No
SH-D	$2,072	($1,573)	$0	$4,052	$4,551	Yes	Yes
HVDS-E	($271,456)	$2,093	$0	$224,274	($45,088)	No	No
HVDS-F	($207,669)	($15,490)	$0	$103,551	($119,608)	No	No

Table 5C: Comparison of Current PPO Components to Proposed PPO Components (MVEC +5% & w/ current transmission costs) for Selected Customer Accounts

Customer Name	Change in Annual DST Costs	Change in Annual Transmission Costs	Change in Annual CTC Costs	Change in Annual PPO Energy Costs	*Change in* Annual Total PPO Costs	PPO Savings Diminish?	Bundled Rate Becomes More Economic?
2B	$245	$0	($291)	$66	$20	Yes	No
3A	$1,668	$0	($678)	$184	$1,174	Yes	No
3B	$575	$0	($771)	$210	$14	Yes	No
3C	$585	$0	($1,871)	$504	($782)	No	No
3D-IRMA	$356	$0	$0	$731	$1,087	Yes	No
3E-IRMA	$489	$0	$0	$562	$1,051	Yes	Yes
3F	$372	$0	($3,705)	$995	($2,338)	No	No
4A	$8,775	$0	($587)	$314	$8,502	Yes	Yes
4B	$2,060	$0	($1,482)	$812	$1,391	Yes	No
4C	$2,099	$0	($5,163)	$2,903	($160)	No	No
4D	$987	$0	($2,471)	$1,397	($87)	No	No
4E	$1,440	$0	($4,750)	$2,570	($741)	No	No
5B	$3,254	$0	($1,824)	$2,151	$3,581	Yes	No
5C	$1,665	$0	($3,161)	$3,578	$2,082	Yes	No
5D	$4,656	$0	($6,888)	$7,518	$5,286	Yes	No
5E	$1,757	$0	($6,940)	$6,950	$1,767	Yes	No
5F	($554)	$0	($8,300)	$8,386	($468)	No	No
6B	$17,487	$0	($2,891)	$4,941	$19,537	Yes	No
6C	$15,875	$0	($4,642)	$7,063	$18,297	Yes	No
6D	$3,712	$0	($5,252)	$8,714	$7,173	Yes	No
6E	$6,040	$0	($8,466)	$12,720	$10,294	Yes	Yes
[illegible]	$9,975	$0	($3,815)	$6,194	$12,354	Yes	No
7C	$25,132	$0	($9,723)	$16,140	$31,549	Yes	No
7D	$27,071	$0	($13,194)	$19,827	$33,704	Yes	Yes
7E	$9,146	$0	($23,821)	$35,717	$21,041	Yes	No
7F	$3,828	$0	($10,436)	$14,429	$7,821	Yes	No
8C	$37,135	$0	$0	$32,743	$69,878	Yes	No
8D	$30,719	$0	$0	$51,866	$82,585	Yes	No
8E	$22,269	$0	$0	$68,987	$91,256	Yes	Yes
8F	$1,148	$0	$0	$63,658	$64,806	Yes	No
9C	$77,973	$0	$0	$65,180	$143,154	Yes	No
9D	$53,682	$0	($30,943)	$65,043	$87,782	Yes	No
9E	$13,324	$0	($58,865)	$98,973	$53,432	Yes	No
10B	$610,109	$0	($5,083)	$126,107	$731,132	Yes	Yes
10D	$211,405	$0	$0	$137,623	$349,029	Yes	No
10E	$186,797	$0	($17,001)	$143,513	$313,309	Yes	No
SH-B	$561	$0	$0	$226	$787	Yes	No
SH-C	$1,379	$0	$0	$1,186	$2,565	Yes	No
SH-D	$2,072	$0	$0	$4,052	$6,124	Yes	Yes
HVDS-E	($271,456)	$0	$0	$224,274	($47,181)	No	No
HVDS-F	($207,669)	$0	$0	$103,551	($104,118)	No	No

Table 6: Summary of Effects on NE Customer Base* Between Current PPO & Delivery Service Components to Proposed PPO & Delivery Service Charges PPO Components Under Various Transmission Cost and MVEC Variants.

	Losers							Winners				
Comparative Situation and Table [#]	# of NE Served Accounts whose annual PPO Savings diminish	% of NE Served Accounts whose annual PPO savings diminish	% annual kWh of NE Served Accounts whose annual PPO savings diminish	Average % Increase in Annual PPO Cost	Estimated Total Annual $ Increase for NE Served Accounts	# of NE Served Accounts who *become* better off on bundled rates	% of total annual kWh of NE Served Accounts who *become* better off on bundled rates	# of NE Served Accounts whose annual PPO Savings improve	% of NE Served Accounts whose annual PPO savings improve	% annual kWh of NE Served Accounts whose annual PPO savings improve	Estimated Total Annual $ Decrease for NE Served Accounts	Average % Decrease in Annual PPO Cost
Proposed DSTs and Transmission Charges [4A]		48.7%	73.46%	4.2%	$3,753,733		1.9%		51.3%	26.54%	-$1,299,251	-2.9%
Proposed DSTs w/ current Transmission Cost [4B]		55.3%	74.06%	4.0%	$4,261,534		3.5%		44.7%	25.94%	-$1,039,247	-2.9%
Current DSTs and Transmission Charges (+5% MVEC) [5A]		52.2%	92.96%	1.7%	$4,705,290		1.6%		47.8%	7.04%	-$9,591	-0.1%
Proposed DSTs and Transmission Charges (+5% MVEC) [5B]		68.9%	91.25%	4.9%	$9,110,815		17.6%		31.1%	8.75%	-$253,640	-2.1%
Proposed DSTs w/ current Transmission Cost (+5% MVEC) [5C]		70.2%	92.55%	5.7%	$10,069,604		18.0%		29.8%	7.45%	-$77,314	-1.2%

*: Excluding 4 HVDS accounts.

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Comed rebuilds its system and its reputation.

In the summer of 1999, the United States was struck by a series of major utility outages as aging T&D systems proved vulnerable to the I twin challenges of extreme heat and extreme demand. New York City, New York, was hit by its worst blackout in more than 20 years. Half a million customers lost power in New Orleans, Louisiana. And in Chicago, Illinois, as a month of recurring outages crippled vital parts of a sweltering city, an angry Mayor Richard M. Daley expressed the voice of many when he demanded immediate action. Comed, he declared, needed to rebuild its system and do it now, starting at "ground zero."

In response, Comed's new chairman, John Rowe, launched a comprehensive overhaul of its T&D system, a US$1.5 billion reliability improvement plan that industry experts called "unprecedented." Rowe demanded a fundamental core change aimed at producing a T&D system that met or exceeded industry standards. His message was simple: "Nothing matters if we don't keep the lights on."

The Long Hot Summer of 1999

In 1999, the first major blackout of Chicago's late summer heat wave began beneath the manholes located along California Ave. In the early morning hours of Friday, July 30, the 12-kV line feeding Cortland Substation short circuited. Within hours, a series of falling T&D dominos had two major substations down, with the power gone and the air conditioning out in nearly 100,000 homes. It was the hottest day of the summer, in what the Chicago Tribune later calculated was the fourth hottest week of the century.

Public anger rose along with the temperature as other T&D components failed over the next five weeks. Manhole fires occurred on August 9 and 10. Chicago's central business district, the Loop, went dark on August 12. Later, power failed at four Chicago icons: Meigs Field, Lake Shore Drive, the Field Museum and the downtown courthouse named for the mayor's father.

These highly visible back-to-back service interruptions dramatically exposed the true depth of problems that had troubled customers, Comed and public officials for several years. Rowe, stated plainly, "I will not tolerate it, and you will not have to."

The Comed Response

Comed hit the ground running. By the time the last service was restored on August 12, Comed had dispatched more than 700 men and women to open manholes and inspect substations across the city. All told, during the first six weeks, Comed devoted an estimated 250,000 additional man-hours and more than US$20 million to the round-the-clock emergency-response effort, above and beyond normal operations.

Two days before the August 12 Loop outage, Rowe had assigned David Helwig to head up a task force to review the July outages and to develop a plan to achieve fundamental improvements. Helwig, who was formerly the senior vice president of Comed's Nuclear Generation Group and has a background in both T&D and nuclear power programs, had already been recognized for introducing fundamental change within Comed's troubled nuclear programs.

Helwig solicited EPRI's Vice President of Power Delivery Dr. Karl E. Stahlkopf to participate closely in Comed's investigation. Stahlkopf called Comed's assessment "the fastest, fullest, most comprehensive T&D investigation ever launched in the history of the industry, taking a blunt look at equipment, design, personnel and operations."

One of the most critical imperatives was to map out and identify the nature and extent of the most serious and time-sensitive challenges, and to do so quickly. During the first 10 days alone, Comed employees inspected virtually every one of Comed's 888 substations.

At the same time, Helwig assembled a team of experienced experts to assess the operation and management of Comed's T&D system, drawing extensively on the technical expertise of EPRI and consulting with such industry leaders as General Electric, Kenny Construction and Asea Brown Boveri.

The Findings

In truth, the reliability hole that Comed found itself in at the end of summer 1999 was dug over a long period of time. The findings were sobering. Substation and feeder capacity planning and capacity additions had not kept up with the heavy load growth spurred by Chicago's booming economy. The problem was not a lack of power; the problem was that the distribution system could not reliably deliver the power at peak times.

To make a bad situation worse, through the years the company had neglected routine maintenance in favor of other projects. The review team found that other major cities - operating T&D equipment not newer, not older, not fundamentally different from Comed's - did not suffer the same breakdowns. The critical difference was rigorous care and maintenance. All in all, Comed faced overloaded feeders and substations, inadequate capacity and redundancy, and poorly maintained equipment, exacerbated by weak planning. The system was cracking under the pressure.

The Recovery Plan

The findings were assembled in less than two months and made public in a 450-page recovery plan, the September 1999 Investigation Report. A blueprint for change, it set detailed criteria for a staggering array of tasks, projects and process improvements pledged to be completed before summer 2000. Physical improvement plans included more than 330 distribution feeder installations and upgrades, 27 large substation transformer upgrades or expansion projects, transmission line inspections and repairs, and the start of an extremely aggressive multi-year improvement program for key Chicago substations. It also called for new discipline and accountability, especially for T&D maintenance.

The Recovery, Summer 2000

Carl Croskey, then distribution group president, was charged with addressing deficiencies in system maintenance that had brought about the crisis. For example, to complete a comprehensive aerial inspection of the overhead transmission system, the company used the helicopter services of Haverfield Corp. The flights revealed more than 2700 critical deficiencies ranging from broken insulators to missing support pins to floating static wires.

Outage analysis in autumn 1999 showed that falling trees and branches were the cause of some 17% of outages. Thus, a key element of Comed's new maintenance program included an exclusive partnership with Asplundh Tree Experts who took over all tree-trimming responsibilities. By May 2000, Asplundh had reduced the trimming cycle to four years, dramatically impacting the number of tree-related outages [Fig. 7].

Comed also recognized that not everything would or could be completed by the summer of 2000. The company had to implement plans that went beyond immediate equipment upgrades and maintenance programs. To ensure that additional stress was not put on areas where improvements could not be accomplished for summer 2000, Comed planning engineers joined efforts with the sales force to procure curtailable load. Surpassing its goal of more than 1200 MW, this targeted load-curtailment effort saved the immediate need for some upgrade projects. Ultimately, because of favorable weather and proactive load management, Comed did not have to call for any system-wide curtailment programs during the summer of 2000.

To protect transformers that were not part of the 2000 improvement plan, additional monitoring was installed to identify potential degradation. The improved monitoring paid dividends. During 2000, newly installed transformer-monitoring systems sent alarms that triggered immediate and proactive inspections. The resulting maintenance was credited with saving imminent failure on no less than five occasions.

The Success

Manpower made a critical difference. Comed employees worked an average of more than 60 hr a week, thus completing most of the distribution system and substation maintenance projects, along with smaller upgrades [Fig. 3]. They were joined by more than 2100 contractors in a sustained partnership to complete the balance of the work, which included installing conduit, pulling cable, performing distribution feeder upgrades, completing substation projects, trimming trees, performing new business hookups, finishing overhead transmission maintenance repairs, and foundation and concrete work.

Other partnerships and alliances also were key to the turnaround. For example, GE/Harris provided turnkey projects for equipment, monitoring and relay upgrades while S&C Electric led a team that installed more than 100 pole top automated switches on the 34-kV system.

Of major concern was the growth of Chicago and the company's ability to support the energy needs of the city. The 2000 plan centered on six Chicago substations known as the "six-pack": Northwest, Diversey, Lakeview, Kingsbury/Ohio, Grand and Jefferson. The most extensive modernization project accomplished was at the Northwest Substation, supplying power to more than 82,000 customers. An entire 12-kV substation was rebuilt over the top of the old one, two 75-MVA transformers were added and other upgrades were completed.

For Diversey, the challenge was even greater. An entirely new substation was erected on an urban site that had been commercial-use land as late as November 1999. Experts predicted construction would take two years to build the 138-/12-kV substation that would house four 50-MVA transformers, but Comed didn't have two years. In the end, it was built and commissioned in about eight months, an almost unbelievable accomplishment of man, machine and management [Fig. 4].

The improvements on the remaining four of the Chicago six-pack included retiring the switchgear at the Lakeview substation and the conversion of feeders to 12 kV for better switching flexibility, making room for future substation work. A new GIS substation [Grand] was built to help load growth for the north end of the Loop business district. Finally, circuit breakers were refurbished and rebuilt at the Jefferson substation, the location that caused the severe 1999 outage in Chicago's growing South Loop.

ABB and Kenny Construction joined forces to complete the bulk of the Chicago six-pack projects by delivering a design, procurement and construction team able to fast track some complicated projects. Working through a minefield of equipment delivery lead times, permit approvals and Comed workforce coordination, the team completed critical maintenance and other operations in some extremely confined urban areas.

While the fast-track nature of these Chicago six-pack projects is not the recommended course of action, the alliance team was able to deliver without significant outages or serious safety incidents. There were of course some trade-offs. The distribution system was at a greater risk because key elements were taken out of service for project cut-overs. Some customers experienced outages because of cable dig-ins, and cable failures caused more widely spread outages because many circuits were switched abnormally for construction purposes. Ultimately, risk mitigation and outage coordination were critical to the success of the projects.

Comprehensive contingency plans were created to address other areas where high loads were projected. Comed secured temporary and portable generators. The centralized Distribution Dispatch Center [DDC] made load forecasts and called for load switching and generator deployment on a day-by-day basis. During the summer of 2000, the DDC did an impressive job of proactively managing the load forecasts with switching steps, thus avoiding any widespread generator use.

Comed again found itself under the gun when a sidewalk network vault roof collapsed in July 2000, triggering a fire and shutting down power to three high-rise buildings in Chicago's downtown. But in less than an hour, generators and emergency personnel were effectively deployed. In sharp contrast to summer 1999, city leaders joined business owners in acknowledging Comed's quick and professional response. Chicago Environment Commissioner William Abolt hailed Comed's response to the fire as substantially better than previous years. He told a Chicago newspaper, "We were really pleased that the first real test of the new emergency plan worked."

More than Equipment

For the T&D turnaround to succeed, John Rowe also demanded a complete overhaul of the company's communications efforts. In 1999, the mayor, the media and other critics described their acute frustration in getting information quickly and accurately. Comed responded with a new plan to enhance communications with government leaders, the media and the Illinois Commerce Commission [ICC] to keep them informed about project plans, progress and outages. Comed also established a timely communications process for informing the public when outages occur, what restoration efforts are underway and estimated times of when power will be restored.

The city of Chicago used Harza Engineering as a third-party overseer to act on the city's behalf and provide objective expertise about the reasonableness and timeliness of Comed's turnaround efforts. This innovative partnership enabled Comed to help regain credibility with stakeholders throughout its service area. Today, Comed provides detailed monthly updates to the ICC and the city about work progress and system performance, a practice of continuous, bare-knuckled scrutiny that is said to be the most extensive public reporting system of any electric utility in the nation.

Fewer, Faster, Better

Comed continues to refine its organization and enter long-term alliance partnerships for engineering and construction support. Helwig's T&D plans for 2001 are as aggressive as for 2000. Today, the company has begun to climb out of the reliability hole. The critical atmosphere has somewhat dissipated. There is ample evidence that the upgrades, maintenance and new construction are showing the kind of measurable results Rowe demanded. The frequency of outages has decreased more than 38% since December 1998 [Fig. 5]. The duration of outages has decreased more than 46% for the same period [Fig. 6].

Each time the company makes another deadline, fulfills another commitment or answers a customer's question, another step is taken out of the hole. More hard work is left but Comed's efforts to date clearly demonstrate that key partnerships, innovative risk taking, and unyielding corporate focus are bringing about the successful rebuilding of both the power delivery system and the confidence of its customers.

Carl Segneri is the vice president of substations and transmission for Comed Energy Delivery. In his 20 years at Comed, Segneri has managed construction, engineering, transmission design and operational analysis. He was also regional distribution leader for the Chicago region, overseeing the inspection and repair of facilities identified as crucial to the proper functioning of the system. In addition to work in T&D, he performed engineering testing work at Dresden Nuclear Station and Will County and Collins fossil generating stations. Segneri holds the BSEE degree from the University of Notre Dame. He is a member of the IEEE.

About Comed

Commonwealth Edison [Comed], a unit of Chicago, U.S.-based Exelon Corp., is one of the nation's largest electric utilities with nearly US$15 billion in revenues. Comed provides service to more than 3.4 million customers across Northern Illinois. Comed's customer base consists of more than 3 million residential customers and nearly 300,000 commercial and industrial customers located in Northern Illinois' six counties. With 8000 employees, Comed designs, operates and maintains more than 75,000 miles [120,701 km] of electric transmission and distribution lines.

Executive Commitment Remains Steadfast

David Helwig's mission was expanded in late 2000 to executive vice president of energy delivery operations, responsible for running the entire T&D organization. Today, David Helwig and Comed Vice Chair Pamela Strobel are continuing efforts to lead one of the most comprehensive utility turnarounds ever. And, as summer 2001 approaches, it appears the combined efforts of new leadership, outside experts and the massive investment of resources and planning are paying off with substantial reductions in the frequency and duration of outages. Still, Comed cannot promise a summer free of outages. "What Comed does pledge," Stroebel told the Chicago city council, "is fewer interruptions, faster restoration and better communications."

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